Renewable and Sustainable Energy Reviews 31 (2014) 746–761

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

A new generation of small hydro and pumped-hydro power plants: Advances and future challenges

G. Ardizzon, G. Cavazzini *, G. Pavesi

Department of Industrial Engineering – University of Padova, Italy

ARTICLE INFO

Article history:
Received 13 August 2013
Received in revised form
10 December 2013
Accepted 18 December 2013
Available online 22 January 2014

Keywords:
Hydropower
Pumped-hydro energy storage plant
Small hydro power plant
CFD
Variable-speed pump-turbine
Optimal management strategies

ABSTRACT

Hydropower is not only a renewable and sustainable energy source, but its flexibility and storage capacity also makes it possible to improve grid stability and to support the deployment of other intermittent renewable energy sources such as wind and solar power. As a result, a renewed interest in pumped-hydro energy storage plants (PHES) and a huge demand for the rehabilitation of old small hydropower plants are emerging globally.

As regards PHES, advances in turbine design are required to increase plant performance and flexibility and new strategies for optimizing storage capacity and for maximizing plant profitability in the deregulated energy market have to be developed.

During the upgrading of old small hydropower plants, the main challenges to be faced are the design of new runners, that had to match the existing stationary parts, and the development of optimal sizing and management strategies to increase their economic appeal.

This paper traces an overview of the prospects of pumped-hydro energy storage plants and small hydro power plants in the light of sustainable development. Advances and future challenges in both turbine design and plant planning and management are proposed. PHES and hybrid wind/solar-PHES are illustrated and discussed, as well as the limits and peculiarities of the new design strategies, based on computational fluid dynamics, for both PHES and small hydropower plants.

Contents

1. Introduction

In the last decades, world electrical energy consumption has significantly increased with a share that has reached 17.7% in 2010 and is predicted to double by 2025 [1].

The increasing concern about environmental aspects has favored a corresponding rapid growth of the deployment of the

* Corresponding author. Tel.: +39 049 8276800; fax: +39 049 8276785.
E-mail addresses: guido.ardizzon@unipd.it (G. Ardizzon), giovanna.cavazzini@unipd.it (G. Cavazzini), giorgio.pavesi@unipd.it (G. Pavesi).

1364-0321/$ - see front matter © 2014 Elsevier Ltd. All rights reserved.
http://dx.doi.org/10.1016/j.rser.2013.12.043

renewable energy sources aimed at the progressive reduction of fossil fuel exploitation and dependence. In such a context hydropower is undoubtedly one of the most mature technologies with an electricity production of about 3500 TWh in 2010 (16.3% of the world's electricity), greater than that of the other renewable sources combined (3.6%), but much smaller than that of the fossil fuel plants (67.2%) [2] (Fig. 1).

In the EU-27 the hydropower generation was 323 TWh in 2010 (9.8% of the European electricity) and around 60% of electricity generation from renewable sources [3].

Even though today hydropower plays a key role in the green energy production, avoiding the combustion of 4.4 million barrels of oil equivalent daily, only 33% of potential hydro resources has been developed and the remaining technical potential is estimated

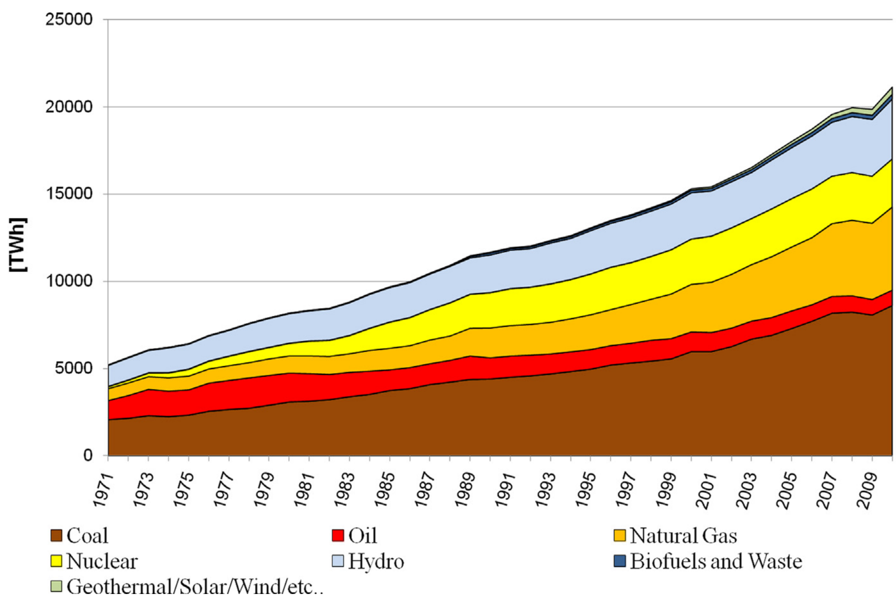

Fig. 1. World electricity generation by fuel.

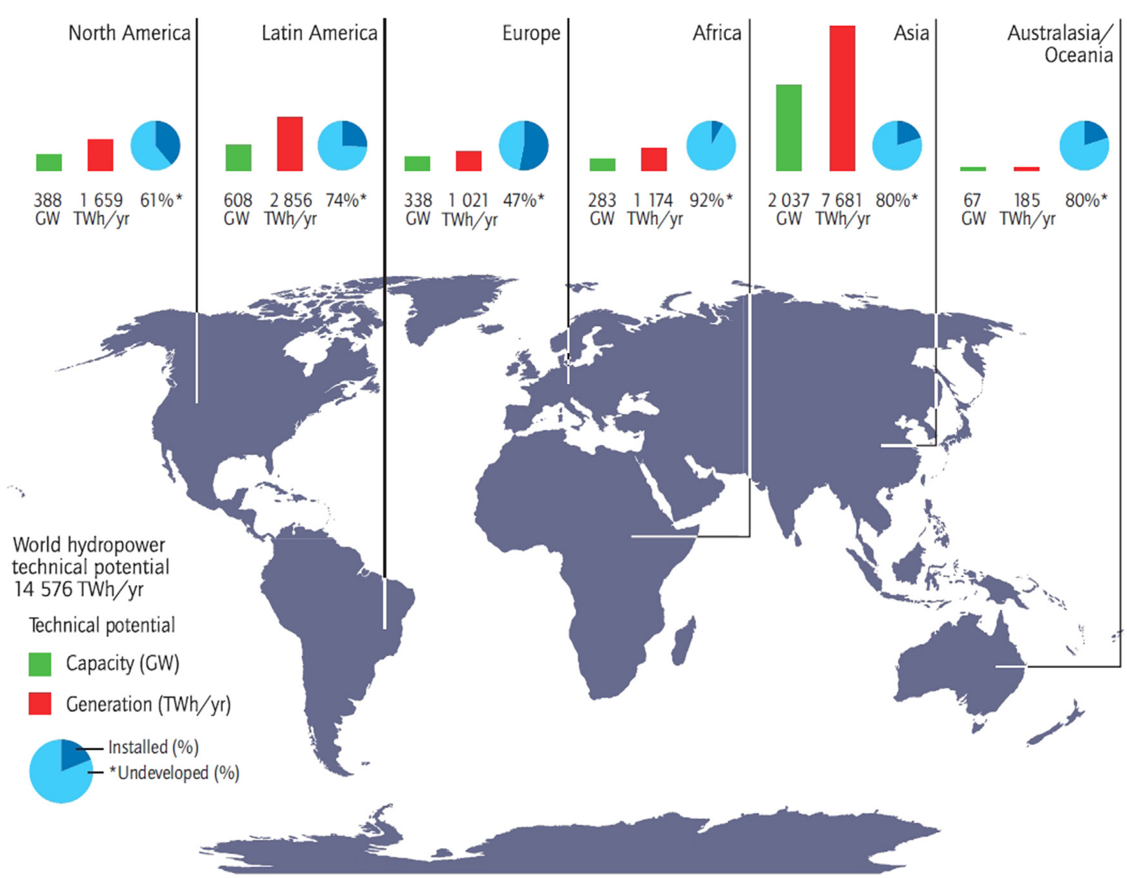

Fig. 2. World hydropower technical potential [2].

to be very high (14,576 TWh/year) [2] (Fig. 2). The highest percentage of undeveloped potential is located in Africa (92%), followed by Asia (80%), Oceania (80%) and Latin America (74%), even though this region is also characterized by two of the top ten hydropower producers in 2010 (Table 1) and by several countries with a very large share of electricity generation obtained by hydropower (Table 2) [2].

Besides the positive effects on climate mitigation, hydropower also presents other considerable advantages: it promotes price stability because, unlike fuel and natural gas, it is not subject to market fluctuations; it reduces environment vulnerability to floods; it contributes to fresh water storage for drinking and irrigation exploitations; it makes a significant contribution to development by bringing electricity, roads, industry and commerce to communities which can benefit future generations as hydropower projects are long-term investments with an average life span of 50–100 years.

Despites numerous examples of excellent, sustainable and safe exploitation of the water resources by hydropower, large hydro projects, which include a dam and a reservoir, encountered a substantial opposition in the latter end of the last century because of their environmental and social implications (landscape, wildlife, biodiversity, population settlement, health and water quality, etc.). This opposition was one of the main factors of the slowdown in the hydroelectricity generation between the late 1990s and the early 2000s [2,3].

However, eliminating large hydropower projects from renewable energy programs will not reduce the power demand, which will be partially satisfied by thermal plants, thereby increasing the global level of greenhouse gas emissions. For instance, it was demonstrated that two pumped-hydro energy storage units combined with a thermal generation unit make it possible to reduce the excess emissions of the thermal unit by 60% [4].

In such a context, a renewed interest in large pumped-hydro energy storage plants and a huge demand for the rehabilitation and repowering of old small and micro-hydro plants are globally emerging both due to further increases in the corresponding share of renewable electricity production and due to the support, in terms of storage capacity, of a wider exploitation of other renewable energy sources such as wind and solar power.

Table 1
Top ten hydropower producers in 2010 [2].

Country	Hydro electricy [TWh]	Share of electricity generation [%]
China	694	14.8
Brazil	403	80.2
Canada	376	62.0
United States	328	7.6
Russia	165	15.7
India	132	13.1
Norway	122	95.3
Japan	85	7.8
Venezuela	84	68.0
Sweden	67	42.2

Even though these renewable energy sources have largely increased in the last years, reaching in 2010 a share of 3.6% of the world electricity generation [1], this share would need to be greatly increased in order to significantly contribute to the reduction of greenhouse gas emissions (GHG). The European Union policy has made great efforts towards developing these resources in response to environmental concerns, but their unpredictable and intermittent characteristics have restrained their deployment because of the negative impact on power system security, stability, reliability and efficiency [5–8].

At present, the electricity grid is highly centralized with a complex system of energy production-transmission characterized by a long distance between power plants and end-users and by a limited use of storage, whose installed capacity was about 127.9 GW in 2010 (2.5% of the world installed capacity) [9]. To ensure the security of the power system, a continuous balance between demand and supply should be guaranteed and this actually limits penetration in the grid of intermittent renewable energy sources, whose energy production is fluctuating, unpredictable and delocalized. For example, as regards the potential wind energy penetration in the electricity grid, an instantaneous increase up to 20% of the total energy production was estimated to be feasible without technical hitches for the grid stability [10]. However, further increases in wind energy generation (up to 80%) are feasible only in isolated grids (smaller than 10 MW), whereas greater electrical grids require energy storage to accept a wind energy penetration greater than 20% [11].

The development of a significant energy storage capacity is, therefore, a necessary solution to favour the deployment of the renewable energy sources not only in isolated grids, but also in interconnected grid systems, as demonstrated by several analyses carried out on a national scale [12–17].

For this reason, the European Union is carrying out a Climate and Energy policy, defined in the Strategic European Technology Plan (SET-Plan) [3], one goal of which is to study more in depth the benefits of storage applications. In such a context, several studies [9,18–23] have been carried out to analyse the current status of the wide range of available technologies (mechanical, electromagnetic, chemical, thermal) in terms of technology maturity, efficiency, energy storage capacity, power discharged capacity, application size, cost of investment, life time and environmental impact.

All these analyses identify Pumped Hydro Energy Storage (PHES) as being the most cost-efficient large-scale storage technology currently available, with an efficiency range of 75–85% and competitive costs (1500–4300 $/kW, 250–430 $/kWh) [23]. In Europe, this technology represents 99% of the on-grid electricity storage [9] with more than 7400 MW of new PHES plants proposed and a total investment cost of over € 6 billion [24]. In spite of this boost provided by the increasing need for storage capacity, one of the major limits for the further development of PHES is the lack of suitable locations for the construction of new facilities [19,25–27]. To overcome this problem, a program, able to identify areas that could be quite easily modified in order to construct the reservoirs of the PHES, was developed [28] and the possibility of excavating underground reservoirs was considered [29,30]. However, in the long-term perspective

Table 2
Countries with more than a half of their electricity generation from hydropower in 2010 [2].

Share of hydropower	Countries	Hydropower Generation
~100%	Albania, DR of Congo, Mozambique, Nepal, Paraguay, Tajikistan, Zambia	54 TWh
> 90%	Norway	126 TWh
> 80%	Brazil, Ethiopia, Georgia, Kyrgyzstan, Namibia	403 TWh
> 70%	Angola, Columbia, Costa Rica, Ghana, Myanmar, Venezuela	77 TWh
> 60%	Austria, Cameroon, Canada, Congo, Iceland, Latvia, Peru, Tanzania, Togo	351 TWh
> 50%	Croatia, Ecuador, Gabon, DPR of Korea, New Zealand, Switzerland, Uruguay, Zimbabwe	36 TWh

to fulfil the increasing storage capacity need, besides the installation of new PHES sites, it would be necessary to adapt and exploit the existing hydropower plants, as was achieved in France during the 1970s and 1980s to support the nuclear power reactors [22] or as recently proposed in Greece to support RES penetration [12]. To reach this aim, the existing hydropower and PHES plants should not only modify their operation strategies in order to maximize the revenue from the day-ahead market and from the regulation services, but also optimize turbine performance by means of innovative design criteria so as to increase the corresponding storage efficiency and to achieve the required greater flexibility. The resulting storage capacity will also favour a different economical approach to investment in RES production based not only on the incentive mechanisms, but also on the techno-economic optimization of the plant operation. This would be aimed at maximizing returns by storing the amount of green production during the low demand periods and selling it to the system during the peak demand periods, thereby providing the required grid stability by means of a fast response time.

As regards small hydropower plants (SHP), the main barriers to the development of new plants are represented by the environmental requirements, in particular those defined by the Environmental Impact Assessments (EIA) and by the Water Framework Directive (WFD). These requirements, generally extremely restrictive, do not properly consider the benefits of the SHP renewable energy production and lead to a limitation of the hours of production and to an increase of the investment costs. So, to safeguard the profitability of the SHP plants and to obtain a further increase of the green energy production, the most cost-effective solutions are represented on the technical side by an increase of the plant efficiency by runner upgrade, and on the economical side by an optimal sizing of the plant accompanied by the definition of optimal management strategies.

The paper is structured as follows: Section 2 focuses on Pumped Hydro Energy Storage Plants. Following a brief introduction to technology advances and challenges, the latest trends in the definition of optimal operating strategies are reviewed: standard configurations as well as innovative hybrid wind-solar/pumped hydro configurations are considered. Section 3 deals with small hydro power plants and, after an overview of the main characteristics of hydraulic turbines, reviews advances and trends in optimal sizing and management of these type of plants. Section 4 focuses on the development of the computational fluid-dynamics for turbomachinery design and in particular on its key role as an innovative and effective design tool in the rehabilitation of small hydroelectric plants and in the development of the new generation of pumped-hydro energy storage plants.

2. Pumped hydro energy storage plants (PHES)

A hydro pumped energy storage plant converts grid-interconnected electricity to hydraulic potential energy (so-called “charging”), by pumping the water from a lower reservoir to an upper one during the off-peak periods, and then converting it back during the peak periods (“discharging”) by exploiting the available hydraulic potential energy between the reservoirs like a conventional hydropower plant.

Pumped energy storage plants are generally subdivided in “closed-loop” (or “off-stream”) plants, when the discharging phase relies entirely on the water previously pumped to the upper reservoir, and in “pump-back” ones, when the discharging phase relies on a combination of pumped water and natural inflow (Fig. 3).

These plants require very specific site conditions to be feasible and viable, among which proper ground conformation, difference in elevation between the reservoirs and water availability.

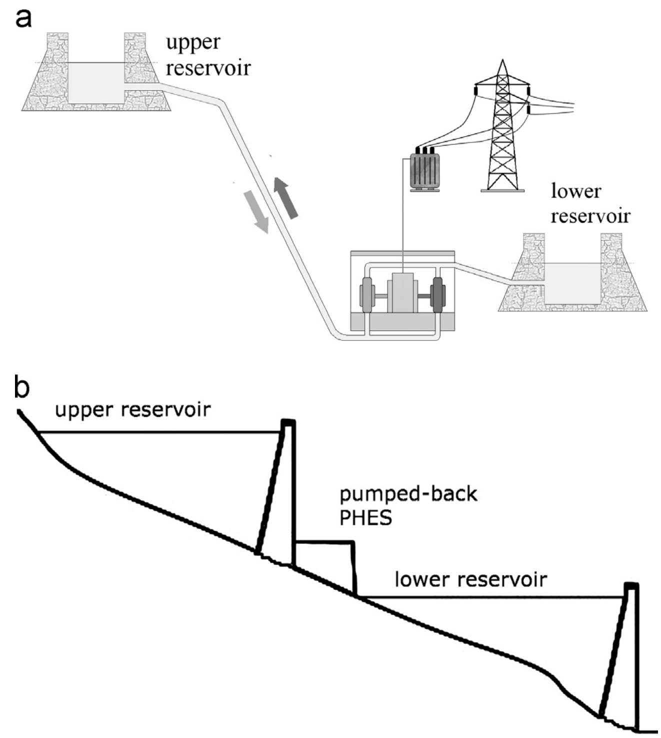

Fig. 3. Closed-loop (a) and pump-back (b) pumped energy storage plants.

For these reasons, the earliest PHES plants were built in the Alpine regions of Switzerland and Austria whose ground conformation together with the presence of hydro resources was suitable for PHES.

The first PHES plants, owned by state utilities, were built to supply energy during the peak periods, allowing the base-load power plants to operate at high efficiency, and to provide balancing, frequency stability and black starts. The period from the 1960s to the late 1980s was characterized by a significant development of these plants mainly due to the corresponding deployment of nuclear power plants whose great inertia was compensated by the PHES flexibility [24]. In the 1990s the reduced growth of the nuclear plants together with the increasing difficult identification of suitable locations significantly limited the further development of new PHES plants. For this reason, in 2006 the average percentage of PHES installed capacity was only about 6% of the full generation installed capacity in the majority of the world countries with the exception of Luxemburg (67%) [24]. This percentage was greater than 10% only for those countries characterized by a significant availability of hydro sources (Croatia) or by a significant percentage of installed nuclear power capacity (Latvia, Japan and the Slovak Republic). USA and Japan still maintained the world highest installed PHES capacity with 20815 MW and 24575 MW respectively, whereas in the European context the largest number (23) of PHES plants are concentrated in Germany [24].

2.1. Variable-speed technology

In recent years, after the liberalization of the market, the increasing interest in renewable energy sources has again turned public attention towards the PHES as a mature and large scale energy storage technology to support green energy production and to provide grid stability. In such a context, several new PHES have been planned in Europe for a total power capacity of 7426 MW [31] and some of them will adopt the variable-speed reversible pump-turbines breakthrough technology, whose

peculiarity is to improve the pump-turbine efficiency over a wider range of operating conditions and to improve the capability in grid regulation of the PHES [32,33].

Usually, pump-turbines are optimized for a specific speed, discharge flow rate and head. At this fixed speed, only limited deviations of head and discharge are allowed since, at off-design operating conditions, the pump-turbine efficiency significantly drops. According to the similarity theory, at different rotation velocities, the operating conditions characterized by the best efficiency are different. The basic idea underlying variable-speed technology is to maintain high efficiency values in the whole working range of the turbine by modifying the rotation velocity of the machine in order to remain near the best efficiency line, thereby maintaining optimal or near-to optimal efficiency values in a wide range of head and flow rates.

Fig. 4 reports a comparison of operating ranges in terms of head and discharge variation between a fixed and a variable-speed pump-turbine with reference to the pumping mode. It is clear that the possibility of varying the speed also significantly increases the operating range of the machine, which was limited, on the one hand, by cavitation problems (broken line on the right) and on the other by an instability operating area (broken line on the left), a typical behaviour of the pump-turbine at part load that should be avoided during the plant operation since it may lead to self-excited vibrations of the hydraulic system.

From an electrical point of view, the possibility of speed variation is obtained by means of a power converter employing power electronic to decouple motor/generator from the grid in terms of reactive power, voltage and frequency, that are properly set independently on the different sides (power-grid and motor/generator).

The corresponding improvements in the design criteria demanded by the variable-speed technology do not significantly increase the cost investment of the power unit compared with a conventional PHES plant [34].

Two of the largest PHES under construction in Europe that are equipped with this technology are Nant de Drance and Linthal, located in the south west and the north east of Switzerland respectively. In both these power plants the use of the variable speed technology was justified by the wide head variation: in the power station of Nant de Drance, equipped with six variable speed units with a unit output of 157 MW (rated speed = 428.6 rpm; speed range = ±7%), the gross head varies between 250 and 390 m; in the power station of Linthal, equipped with four variable speed units with a unit output of 250 MW (rated speed = 500 rpm; speed range = ±6%), the gross head varies between 560 and 724 m (Table 3). Table 4 reports the project features of another important installation, that is the PHES of Goldisthal, in Germany, equipped with two fixed units and two variable-speed units.

It is interesting to highlight that in these plants the design priority was given to flexibility in pumping mode, maximizing the pump operating range, whereas in other cases, such as the PHES of Tehri under-construction in India (four variable-speed units of 255 MW; rated speed = 230.77 rpm; speed range = ±6%) the hydraulic design was optimized to increase the global plant efficiency (Table 3). These different design strategies, aimed at maximizing the plant revenue, are due to the different electricity market regulations and in particular to the existence (or not) of a remunerative regulation market, that could significantly affected the definition of the plant management strategies (Section 2.2).

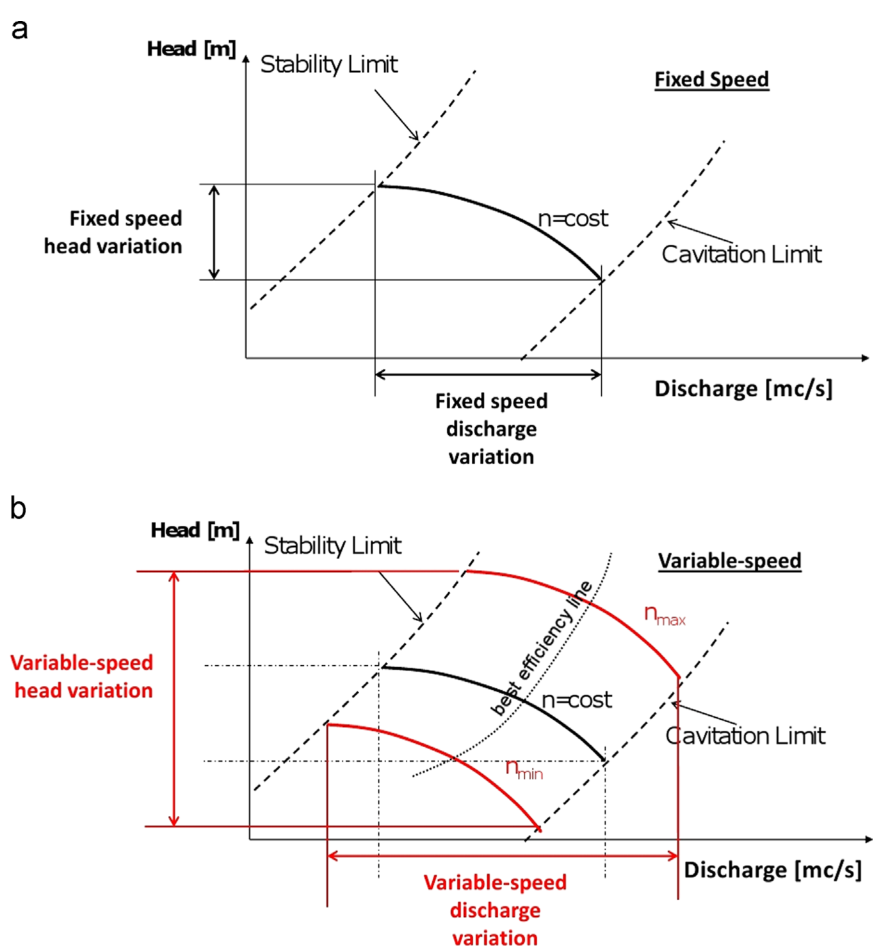

Fig. 4. Comparison of operating domains between fixed (a) and variable-speed (b) pump-turbines (pumping mode).

Table 3
Project features of the PHES of Nant-de-Drance and Linthal.

Project features	Nant de Drance 2019	Linthal 2015	Tehri 2016
Rotational synchronous speed	428.6 [rpm]	500.0 [rpm]	230.77 [rpm]
Speed range	±7%	±6%	±6%
Head variation	250/390 [m]	560/724 [m]	830/740 [m]
Nominal output per unit	157 [MW]	250 [MW]	255 [MW]
Maximum pump discharge per unit	56 [m^3/s]		
Maximum turbine discharge per unit	60 [m^3/s]		
Generator mode	175 [MVA]	280 [MVA]	278 [MVA]
Motor mode	172 [MW]	250 [MW]	
Runner diameter	6.009 [m]	4.230 [m]	

Table 4
Project features of the PHES of Goldisthal.

Project features	Goldisthal
Rotational synchronous speed	333 [rpm]
Speed range (2 units)	+4%/−10%
Head variation	279.2/334.0 [m]
Nominal pump discharge per unit	80 [m^3/s]
Nominal turbine discharge per unit	103 [m^3/s]
Nominal output per unit	265 [MW]
Runner diameter	4.593 [m]

Even if these plants represent the starting point of a new generation of PHES, the possibility in terms of speed variation is limited to about ±10% due to the lack of full variable-speed design criteria, allowing the pump-turbine to operate at a high efficiency in a wide range of rotation velocities, and to the lack of a full power converter technology, enabling a full-range variable speed turbining and pumping (Tables 3 and 4).

As regards the power converter technology, significant advances have been made in recent years, as for example the 100 MVA variable speed frequency converter provided by ABB for the PHES of Grimsel 2 (Switzerland), enabling a wider variable speed pumping (±12%) but not turbining. However, to increase the voltage range and to reduce cost, size and losses still remain the main challenges to face in order to develop a ±100% power converter.

As regards the mechanical equipment, Computational Fluid Dynamics (CFD) has allowed significant advances to the understanding of the reasons of the unstable behaviour of the pump-turbines [35–37] that prevent PHES from operating at low load and seems to be associated to the development of fluid-dynamical phenomena due to the rotor–stator interaction (see Section 4.1). However, innovative design criteria allowing electricity production in the whole operating range (0–100% of the peak power) still have to be developed and certainly represents the future challenge for the development of a new generation of pump-turbine.

2.2. Optimal operating strategies for pumped hydro energy storage plants

In a liberalized electricity market, pumped hydro energy storage represents a merchant unit whose revenue derives not only from the electricity trading in the day-ahead market, but also from regulation services selling in the ancillary reserve markets.

As regards electricity trading, the profit of the PHES is strictly connected with selling hydropower-generated electricity at a high market clearing price (MPC) in the generation mode and with purchasing it at a low MPC in the pumping mode. However, since the conversion process (electricity–mechanical energy–electricity) is unavoidably characterized by energy losses, to make revenue, the purchasing price should be lower than the selling price of a value depending on the plant conversion efficiency (the so-called "round-trip efficiency"), that was assumed to be at around 67% by Lu et al. [38] and around 75% by Castronuovo et al. [39].

As for the ancillary markets, the participation of the PHES is defined on an hourly basis and is remunerated by an hourly ancillary service price to which an hourly spot price is added if the plant is called to generate electricity [38,40].

The resulting profit of a PHES plant operating both in the day-ahead market and in the regulation market is therefore represented by

$$R = R_{generation} + R_{regulation} - C_{pumping} - C_{O\&M} \tag{1}$$

where R is the plant profit, $R_{generation}$ is the energy revenue received from the day-ahead market, $R_{regulation}$ is the regulation revenue received from the ancillary markets, $C_{pumping}$ are the pumping costs and $C_{O\&M}$ are the operation and maintenance costs. In a deregulated market with prices varying on a hourly basis, the profit $R_{[0,T]}$ of a PHES plant operating over a period of T hours depends on the hourly prices P_{gen} (€/MWh) received for generating E_{gen} (MWh), on the hourly spinning reserve prices P_{rs} (€/MWh) received for generating E_{rs} (MWh) in the regulation market, on the hourly non-synchronous reserve prices P_{rn} (€/MWh) received for staying off-line without producing E_{rn} (MWh), on the hourly purchasing prices P_{pump} (€/MWh) paid for pumping and on the operation and maintenance costs, assumed to be constant

$$R_{[0,T]} = \sum_{i=1}^{t_g} E_{gen} P_{gen}(i) + \sum_{j=1}^{t_{rs}} E_{rs} P_{rs}(j) + \sum_{k=1}^{t_{rn}} E_{rn} P_{rn}(k) - \sum_{l=1}^{t_p} E_{pump} P_{pump}(l) - C_{O\&M} \tag{2}$$

where t_g, t_{rs}, t_{rn} and t_p are the number of hours spent by the plant in generating mode, in spinning regulation mode, in non-synchronous regulation mode and in pumping mode respectively.

Since the price volatility of the electricity market does not necessarily follow the load trend, proper operation strategies for maximizing the plant revenue should be defined.

In such a context, several studies have been carried out to define the optimal bidding strategy for individual PHES with reference to different time horizons (daily, weekly or monthly). All these algorithms were based on an objective function to be maximized, taking into account some technical constraints.

In 2004, Lu et al. [38] focused their attention on an individual PHES with a storage capacity of more than 10 h and developed a multi-stage optimization algorithm based on a weekly horizon, considered to be a proper period for the optimal use of the water storage capacity. Their algorithm maximizes the profit of the plant by considering the revenue deriving by both the day-ahead market and the ancillary services market. According to their model, the day-ahead market price is forecasted on an hourly basis in a weekly time period, whereas the ancillary market prices (P_{rs} and P_{rn}) are supposed

to be constant

$$R_{[0,T]} = \sum_{i=1}^{t_g} E_{gen} P_{gen}(i) + E_{rs} P_{rs} t_{rs} + E_{rn} P_{rn} t_{rn} - \sum_{l=1}^{t_p} E_{pump} P_{pump}(l) - C_{O\&M} \quad (2)$$

In the optimization algorithm, the weekly forecasted day-ahead market curve (Fig. 5a) is sorted by ascending prices (Fig. 5b) and the profit of the PHES plant is optimized by progressively increasing the pumping time t_p and checking for the maximum profit (Eq. (2)).

The technical constraint represented by the maximum storable energy due to the upper reservoir dimensions (E_{max}) is not considered in the optimization algorithm, but it is applied as a corrective criterion of the optimal solution. In the limited time intervals of the optimal solution in which the constrain is violated, the unconstrained optimization algorithm is performed again until no violations are identifiable in the weekly time period (Fig. 6).

In 2009, Kazempour et al. [20] proposed a weekly-based optimization algorithm still aimed at the maximization of the plant profit. This algorithm considers the weekly forecast not only of the daily-ahead market but also of the ancillary markets and in particular of the spinning and regulation markets on an hourly-based price variation (Eq. (2)).

In 2011, Connolly et al. [40] limited their analysis to the day-ahead market and compared different operation strategies aimed at maximizing the plant revenue deriving from the electricity trading in one year of plant operation (T=8760 h)

$$R_{[0,T]} = \sum_{i=1}^{t_g} E_{gen} P_{gen}(i) - \sum_{l=1}^{t_p} E_{pump} P_{pump}(l) - C_{O\&M} \quad (3)$$

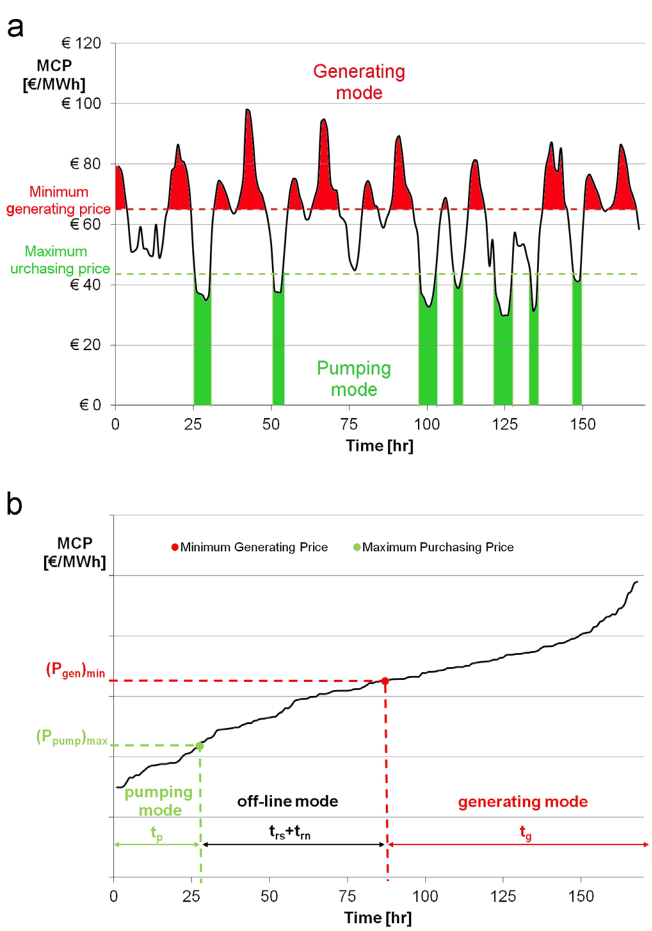

Fig. 5. Convenience limits for the operating modes of a PHES in the day-ahead market: (a) weekly day-ahead market curve; (b) weekly day-ahead market curve sorted by ascending prices.

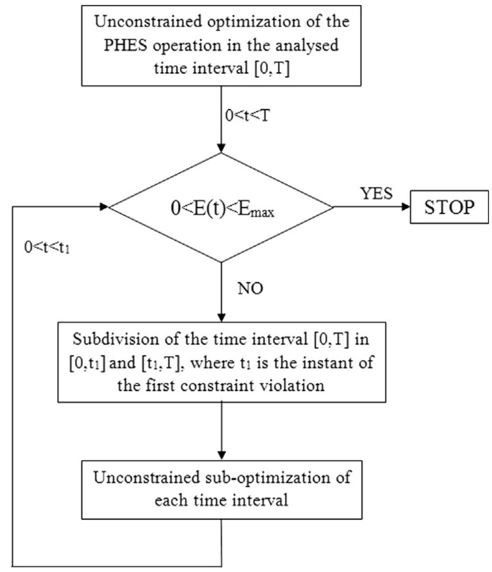

Fig. 6. Summarizing scheme of the optimization strategy proposed by Lu et al. [38].

They demonstrated that in the hypothesis of an accurate prediction of the day-ahead hourly prices, an operating strategy aimed at maximizing the revenue only of the next-day can be more efficient than an operation strategy aimed at maximizing the revenue of the entire year.

Algorithms were also proposed to define optimal operation strategies of combined hybrid wind/photovoltaic hydro energy storage plants. In 2004, Castronuovo et al. [39] developed an optimization approach by means of a primal-dual interior point algorithm aimed at maximizing the plant profit $R_{[0,T]}$ on a 2-day horizon period (T=48 h)

$$R_{[0,T]} = \sum_{i=1}^{t_g} E_{gen} P_{gen}(i) - \sum_{l=1}^{t_p} E_{pump} P_{pump}(l) - C_{st} \Delta E_{cap} - C_E \Delta E_0 \quad (4)$$

where C_{st} and C_E are properly defined penalties for increases in storage capacity ΔE_{cap} and in the initial energy level ΔE_0 of the upper reservoir.

In this case, the plant production E_{gen} is the sum of the energy produced by the hydro generator$E_{hydro}|_{gen}$and of the amount of energy produced by the wind generator and delivered to the network $E_{wind}|_{gen}$

$$E_{gen} = E_{wind}|_{gen} + E_{hydro}|_{gen} \quad (5)$$

whereas E_{pump} is the energy purchased from the network for pumping water that, added to the possible surplus of wind generation not delivered to the network $E_{wind}|_{pump}$, defines the global amount of energy stored

$$E_{storage} = E_{wind}|_{pump} + E_{pump} \quad (6)$$

As regards the reservoir capacity, the model makes it possible to evaluate the minimum amount of incremental storage capacity to follow a specified power demand curve and thereby also optimize the storage size. As regards technical constraints, a maximum allowed wind power exchange with the system was fixed to guarantee the grid stability. Even though the strategy definition only considers the day-ahead market, the combined optimization of strategy and storage sizing made it possible to gain not only in plant profit, but also in wind energy production. The importance of an optimal sizing of a combined wind-hydro storage plant was studied in depth by Khatibi and Jazaeri [41], that presented different optimization techniques (single or multi-objective

optimizations, parametric studies, sensitivity studies) aimed at maximizing the wind energy penetration by optimal plant design.

The possibility of increasing the wind energy penetration through the optimal combination with PHES was also demonstrated by Dursun et al. [42] and by Bueno and Carta [43] that developed a techno-economical multi-stage algorithm. On the basis of technical and economic databases of the commercial plant components, this algorithm defines an optimum-sized system aimed at maximizing the exploitation of the wind energy source without penalizing the grid stability. The model considers not only investment, operating and maintenance costs, but also those costs associated with environmental damage caused by energy production.

In 2012, Ding et al. [44] presented a stochastic optimization of the daily operation strategy of a hybrid wind-hydro energy plant aimed at maximizing plant revenue. To consider the influence of forecast uncertainties of the next-day wind power output on the optimization, the model was based on chance constraints and scenario analyses. Start-up and shutdown costs of the PHSP units as well as penalties for output deviation were considered.

Much more complex algorithms have been recently proposed to formulate an efficient management optimization procedure of large-scale hydropower systems, aimed at increasing the exploitation of the intermittent renewable sources and at supporting and increasing the power grid stability. However, the operation of these systems represents a mixed, non-linear and non-convex programming problem and, up till now, optimal solutions have only been found by approximation of the original problem. Different methods were adopted: dynamic programming models [45], non-linear programming models [46], genetic algorithms [47], simulated annealing [48], ant colony algorithms [49], multi-stage combined models [50], and particle swarm optimization models [51–55].

These algorithms, in comparison with the above mentioned simplified ones, have certainly increased the possibility of considering a complex model by increasing the number of variables to optimize. However, the definition of a model properly considering the techno-economical interaction between the electricity market and the operating plant capability still remains a key-challenge not only for working plants in terms of revenue maximization but also for planned plants since it allows to evaluate the investment profitability on one side, and to define the most proper design strategy on the basis of the electricity market in which the plant will be required to operate on the other side (as seen in Section 2.1). For example, as regards the electricity market, to consider only the day-ahead market or a simplified model of the ancillary markets could negatively affect the evaluation of the investment profitability of a PHES since in the next 10 years the forecasted spread between the maximum and minimum electricity price in the day-ahead market will be significantly reduced due to the flattening of daily power load curve. As a consequence of the flattening of the electricity price curve, in a long-term view the revenue for a PHES will mainly derive from the ancillary services and the correct evaluation of the plant profitability cannot leave these revenues out of consideration or simplify their determination. Another important aspect, frequently neglected in the models, is the influence of the forecasts uncertainties of the electricity markets and of the wind/PV power output on the analysis results.

To correctly evaluate the capability of a PHES of interacting with the electricity markets, the economical model of the markets should be properly combined with an operational model of the plant that considers the real grid-connection capability of the plant by taking into account head and flow rate operating range, variable-speed effects on the operating range, pump-turbine stability limits, storage capacity, losses, response times for load variation in generation and pumping mode, response times for variation of the working mode (pumping to production and production to pumping) and dynamical aspects.

Up till now, none of the studies proposed in literature have considered in details all the above mentioned economical and technical aspects and hence the ambitious goal of a realistic simulation of the interaction between the PHES and the electricity market still remains a challenge due to the complexity of system to model and due to the significant computing costs.

3. Small hydro power

Hydropower on a small scale has not an international agreed definition and its upper limit can vary between 2.5 and 30 MW, even though the most widely accepted value is 10 MW.

Being among the energy storage technologies currently available on a small scale, it is recognized as one of the most cost-effective because of its predictable energy characteristics, its long term reliability and its reduced environmental effects [56,57]. Unlike large scale hydropower, whose development is associated with the building of large dams, small hydro power plants is generally “run-of-river”, with a weir crossing the river and little or no water stored.

Like pumped-hydro energy storage plants, small hydro-power plants require specific characteristics of the installation sites to be feasible, such as a natural head and the possibility of water power harnessing [58]. Depending on site characteristics, such as available head and flow rate, and on the selected running speed of the generator, different turbine types with different operating range and performance characteristics are available and can be divided into impulse and reaction turbines.

In impulse turbines the water remains at atmospheric pressure and the energy exchange is only based on the kinetic energy variation, whereas reaction turbines are characterized by a runner fully immersed in water. Since reaction turbines exploit the available head in terms of both pressure and kinetic energy variation, a draft tube is placed downstream the runner not only to discharge the fluid but also to increase the energy exchange owing to a further pressure reduction induced at the runner outlet.

Impulse turbines can be divided in Pelton, Turgo and cross-flow turbines. The most important impulse turbine is undoubtedly the Pelton turbine, patented in 1880 by Lester Allen Pelton. It is composed by one or more penstocks, equipped with proper nozzles, and by a wheel, whose blades are split buckets properly distributed around its periphery (Fig. 7a). The water jet, coming out from each nozzle and directed tangentially at the wheel, heats the buckets and is split in half, before being deflected back almost 180°. The consequent moment of momentum variation determines the turbine energy exchange.

Turgo turbines are similar to Pelton turbines, but are characterized by a different blade shape and by a different relative dispositions between runner and penstocks (Fig. 7b). The jet strikes the plane of the runner at an angle of about 20° so that the water enters the runner from one side and comes out from the other, eliminating the interaction hazard between flows discharged by different buckets, a risk that could affect the Pelton operating range instead, thus limiting the maximum flow rate.

Cross-flow turbines are simpler and cheaper than the other impulse turbines and were patented after some evolutions in 1933 by A.S. Mitchell and F. Ossberger (Fig. 7c). The jet water enters on one side of a drum-like runner and leaves it on the opposite side after a double passage through the runner blades.

Reaction turbines can be divided in Francis and axial turbines. Francis turbines, patented by James Bickens Francis at the end of the nineteenth century, are mixed-flow reaction turbines composed by spiral case, distributor, runner and draft tube (Fig. 7d).

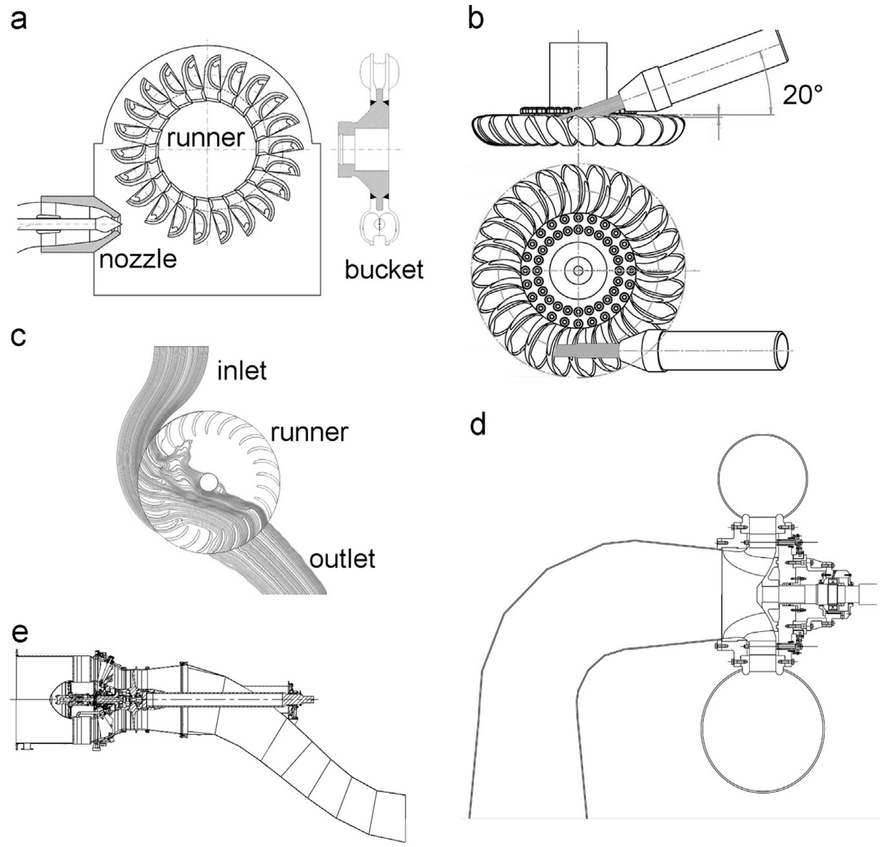

Fig. 7. Scheme of different types of hydraulic turbines: (a) single-jet Pelton turbine; (b) Turgo turbine; (c) cross-flow turbine; (d) Francis turbine; and (e) Kaplan turbine.

The spiral case receives the flow and distributes it peripherally to the distributor, represented by mobile guide vanes whose aim is to control the flow rate entering into the runner and to define the flow angle at the runner inlet.

The axial flow reaction turbines include Kaplan and propeller turbines and are generally composed by guide vanes, a runner and a draft tube. Once it entered the turbine, the water received a swirl component by the guide vanes, that is almost completely absorbed by the runner, thus determining the energy exchange. The water is often directed in the draft tube with a little residual angular momentum to prevent boundary layer detachments. Propeller turbines are often characterized by adjustable guide vanes to vary the flow rate, whereas in Kaplan turbines even the runner blade can be adjusted (Fig. 7e). Even if the mechanisms for adjusting runner and guide vanes increase the machine cost, they bring about a significant improvement of the efficiency at part load, as can be seen in Fig. 8.

The comparison in terms of efficiency and operating range between turbines highlights that Pelton, Kaplan and cross-flow turbines retain high efficiency values even at part loads; instead, quick Francis turbines and fixed pitch propeller turbines are characterized by a rapid efficiency fall below 50% and 80% of the design flow rate respectively.

3.1. Optimal sizing

Since most of the rare high-head installation sites have been already exploited, the great potential of small hydro power is represented by low-head sites, whose economical attractiveness is strictly connected with an optimal design of the electro-mechanical equipment, mainly represented by turbine and generator.

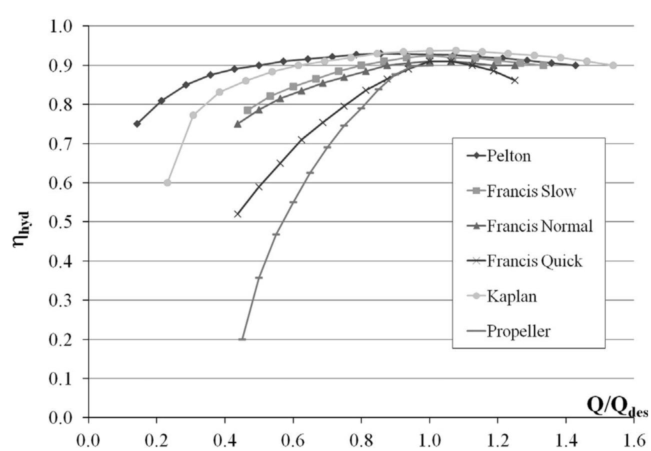

Fig. 8. Turbine efficiency characteristics.

The capacity sizing of a small hydropower plant is strictly connected with flow availability and is based on the analysis of the flow duration curve (Fig. 9). The flow duration curve is a cumulative distribution of the stream flow rate of a site on an annual basis and shows the percentage of time that the site water flow equals or exceeds a specific value.

The available flow rate range of the site is included between the maximum flow rate flowing for at least 1 day per year (Q_{max}) and the minimum flow rate flowing into the site (Q_{min})

$$Q_{min} < Q < Q_{max} \tag{7}$$

This flow rate cannot be fully exploited, since it is established by law that a reserved flow (RF), a sort of environmental flow, should be released downstream to keep the ecosystem in the conditions

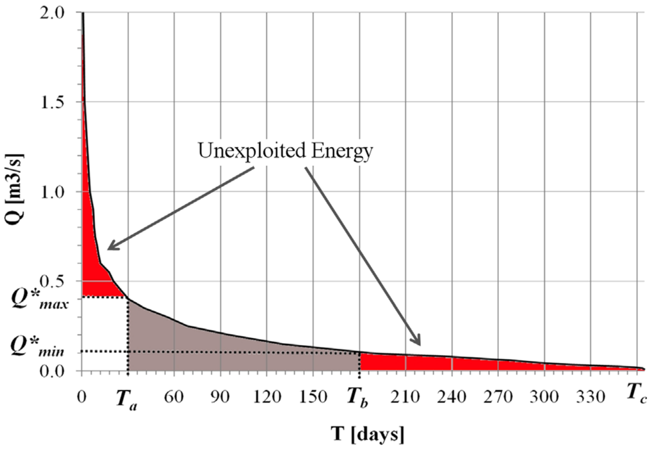

Fig. 9. Example of flow duration curve.

that prevailed before the power plant construction. Therefore, the flow rate range effectively exploitable is obtained from the flow duration curve after the RF subtraction.

A further limit on the flow rate exploitation is represented by the turbine chosen since each turbine operates with acceptable efficiency between a minimum flow rate Q^*_{min} and a maximum flow rate Q^*_{max} (Fig. 9). Therefore, for flow rates smaller than Q^*_{min} the plant should be stopped, releasing all the available flow rates, whereas for flow rates greater then Q^*_{max} the plant is not be able to exploit the exceeding water quantity released downstream without being exploited. Depending on the turbine, the energy production over a time period T can be determined as

$$E = \int_0^T P(t)dt = \int_0^T \rho g Q(t) h(t) \eta_{hyd}(t) \eta_{mech} \eta_{el} dt \tag{8}$$

where $P(t)$ is the power obtained by the turbine, ρ is the water density, $Q(t)$ is the flow rate, $h(t)$ is the net head, η_{hyd} is the hydraulic efficiency (Fig. 8), η_{mech} and η_{el} are respectively the mechanical and the electrical efficiencies. The net (also called "effective" or "available") head $h(t)$ is obtained by the gross head h_g (i.e. the difference between the level of the upper reservoir and the level of the tailwater) after subtraction of the hydraulic losses $h_r(t)$ in the pipeline connecting the reservoir with the turbine and of the kinetic energy discharged by the turbine without being exploited

$$h(t) = h_g - \left(h_r(t) + \frac{v^2_{outlet}(t)}{2g} \right) \tag{9}$$

where v_{outlet} is the water velocity at the draft tube outlet. According to Eq. (9), the draft tube is an integral part of the turbine.

Several studies focused their attention on the design of a small hydro power plant as its features played a key role in the definition of the plant profitability. Hosseini et al. [59] determined the optimal installation capacity of a plant as a compromise between technical, economic and reliability indices. However, the algorithm did not enter into the details of the electro-mechanical design.

A non-linear programming method was adopted by Almeida et al. [60] who optimized the project configuration of a small-hydro power plant by considering technical, hydrological, operational, economic and financial aspects. The model considered different possible hydrological and electricity market scenarios, that significantly affected the optimal project configuration. In 2007, Anagnostopoulos and Papantonis [61] carried out a multi-objective optimization study to determine the best compromise between the economic benefits of the investment and the hydraulic potential exploitation in terms of annual energy production and river water exploitation. Niadas and Mentzelopoulos [62] focused their attention on the influence of the flow duration curve on plant capacity sizing and presented a methodology for its probabilistic treatment. The influence of the flow duration curve on plant sizing was also highlighted by Peňa et al. [63] who developed a procedure for estimating the water flow of a site on the basis of time series forecasting methods. Different techniques aimed at enhancing the available historical data were verified and the obtained flow duration curve was exploited for determining the turbine design flow rate on the basis of a fixed capacity factor. A different approach was proposed by Borges and Pinto in 2008 [64], who presented a stochastic method for analysing the influence of river inflow variations and generator unit availability on the power plant availability. Their analysis, starting from known plant characteristics (historical river flow data, height, turbine type, turbine characteristics, generator characteristics), makes it possible to determine the expected value of the annual power plant generation, the flow duration curve and several reliability indices. Possible generation unit failures are also considered in order to define also the risk level associated with the expected energy production. In 2008, Bockman et al. [65] combined the optimal sizing of a small hydropower plant with an analysis of the influence of the uncertain electricity prices on the plant revenues and developed a real options-based model to find the electricity price limit for a profitable investment.

In 2011, Santolin et al. [66] considered the importance of significant technical aspects, such as turbine type, cavitation behaviour and turbine dimensions, in determining the capacity installation size and proposed a method based on technical and economic aspects. Seven design parameters were considered: the turbine type, the main turbine dimensions, the maximum installation height to avoid cavitation inception, the annual energy production, the installation costs, the Net Present Value (NPV) and the Internal Rate of Return (IRR) as economic indices. Starting from the flow duration curve, the procedure highlighted the importance of a simultaneous analysis of all these aspects to a proper definition of the design operating conditions aimed at guaranteeing not only plant profitability, but also its feasibility.

Due to the last advances in hydro technology, one important aspect to consider in the analysis of the optimal design in small hydro applications should be the use of the variable speed technology in installation sites characterized by significant head and/or flow rate variations. The possible application of this technology could significantly increase the plant profitability by increasing the hours of production, and its implementation in the optimization algorithm will certainly represent a significant advance in the optimal sizing of a small hydro power plant. Moreover, since the uncertainties in the flow duration curve and in the forecast electricity prices could affect the analysis results, a risk analysis related to these aspect could represent a future challenge to add to standard optimization strategy.

3.2. Optimal operation strategy for small hydro power

The choice of proper design operating conditions is undoubtedly a fundamental goal for maximizing both investment profitability and the exploitation of the hydraulic potential of water resources. However, once the plant goes into operation, to maintain the unit efficiency and to maximize the plant revenue, the electro-mechanical component performance should be preserved and the operating strategy should be optimized in relation to inflow variations and market fluctuations.

In 2003, Liu et al. [67] developed a method of monitoring and verifying the economic performance of an operating hydropower plant by using new performance indices based on the reachable efficiency and the operating efficiency associated with the maintenance level and with the operation management level of the

plant respectively. These new concepts provide decision making support tools, both for planning refurbishment and maintenance activities and for suggesting new operation strategies.

To analyse the plant performance under specified operating conditions, Garrido et al. [68] developed a simulation tool based on an object oriented modelling language, that allowed to model different configurations of hydropower stations with the possibility of choosing different numbers of turbines and spillway gates. The tool made it possible configure plant parameters and to simulate the plant behaviour at different operating conditions and thereby obtain useful information on the plant behaviour, such as reservoir level, water flows, turbine efficiency and so on. However, simulation tools like those proposed by Liu et al. [67] are highly user dependent since they are based on the plant parameters manually adjusted by the operator and do not guarantee the definition of an optimal operating strategy, such as that obtained by applying a properly defined optimization procedure.

Fleten and Kristoffersen [69] developed a multi-stage mixed-integer linear stochastic program to define an optimized short-term production plan complying with the day-ahead commitments of the previous day. Starting from a production plan scheduled in time by the results of the day-ahead auction, the procedure sets out to identify the expected production between the various parts of the plant in order to achieve effective and efficient operation. The uncertainties of the day-ahead market prices and of the reservoir inflows due to the variable market conditions and to the unpredictable weather situations are taken into consideration in the planning by the stochastic programming framework. The procedure was originally proposed for small hydro power plants, but could be implemented in more complex large hydropower systems thanks to the mixed-integer linear programming approach that makes it possible to model start-up costs and discrete hydro unit-commitment constraints.

A further improvement in the definition of an optimized short-term production plan was proposed by Catalao et al. [70], whose evaluation was based on a mixed-integer non-linear programming approach considering the non-linear dependence between power generation, water discharge and head. Even though this approach was shown to increase the computational costs of the analysis, it was possible to define hydroelectric operating conditions with greater accuracy and, in particular, to take into account the head dependency of a short-term production plan.

Even though these algorithms represent a significant advance in the definition of the optimal management strategies of a small hydro power plant, they require to be further improved by the implementation of models considering series/parallels of large/small hydro power plant in which the management strategy of one plant is affected by the management of the others. An example is represented by one of the most interesting possible application of the variable-speed technology in the small hydro field, that is the exploitation of the reserved flow of a large hydro power plant [71]. The modelling of the head dependency of the small hydro production plan from the management strategy of the large one (that could be a PHES) is undoubtedly an extremely complex aim and is one of the most interesting challenge in this research field.

4. CFD as a tool for improving hydraulic turbine and pump-turbine performance

The peculiarity of Computational Fluid Dynamics (CFD) is its capacity to calculate the flow field around an arbitrary obstacle or through a channel of an arbitrary shape via the numerical solution of the equations that describe the flow development (Navier–Stokes equations, energy equation, global and partial continuity equations, etc.).

Over the years, due to the limits in calculation capacity and speed, not every type of flow field (unsteady, three dimensional, compressible, turbulent, reacting, etc.) could be calculated and the governing equations were simplified in order to describe with more or less accuracy the flow field to be analysed.

The history of computational fluid dynamics started at the beginning of the last century when the reduced (first human and then numerical) computation capacity limited the analyses on two-dimensional flow fields, whose governing equations were simplified by the linearized potential equations solved by conformal mapping or singularity method [72,73]. It was only in the 1970s that the first 3D models were numerically analysed by application, in the fluid-dynamics field, of the finite difference method (FDM) and the finite element method (FEM), historically originating from the field of structural mechanics and aerodynamics [74,75]. These codes demonstrated the possibility of numerically solving with good accuracy both 2D and 3D potential flow problems and the possibility of analysing complex geometries thanks to the FEM way of modelling by triangular and rectangular 8-node parabolic elements.

As regards FEM applications in the turbomachinery field, fluid-dynamical analyses of stationary and rotating rows were initially carried out by means of quasi-3D approaches in which the flow was approximately reconstructed by a combination of the numerical meridional and blade-to-blade flow fields [76,77]. In spite of the limitations of such an approach, whose results were reasonably accurate only for strongly accelerated flows and close to the best efficiency point, some useful information could be already derived for turbomachine designers.

However, even though improvements to the quasi-3D inviscid approach were successively obtained by adding 3D-boundary layer calculations, the simulation of the flow fields in radial runners was still not accurate enough since the majority of the 3D-effects developing in them was driven by vorticity rather than by viscosity. For these reasons, in the 1990s, the need to correctly model the vorticity-driven secondary flows resolutely addressed towards a fully inviscid 3D Euler code, as the computational capacity and the method accuracy were not still ripe for directly stepping into Navier–Stokes simulations [72]. These codes made it possible to analyse with a high degree of accuracy the runner performance at design and off-design operating conditions, as long as the real flow was not dominated by viscous effects, and this capability made it possible to infer the real possibility of transforming the numerical analysis from a research tool to a practical and extremely useful design tool. However, in this period the hydraulic industry was facing important challenges due to the emergence of a huge demand for rehabilitation and upgrading of old hydropower plants. Relying only on previous experience by scaling previous turbine designs was becoming a hazardous strategy owing to the numerous constrains imposed by the existing plants and the uncertainties connected to the attainment of the increase in demand of power. Furthermore, resorting to model tests was also too expensive because the cost of a medium size runner model was nearly the same as the full-scale prototype. So, to face the increased demand for very high-performance hydropower plants, new CFD-based design approaches were proposed, in which the new runners were supposed to be analysed and compared with the old ones by CFD, greatly limiting the support of model tests. This revolutionary design strategy promoted the introduction of Navier–Stokes codes for the computation of both turbulent and viscous effects. In contrast to Euler equations, Navier–Stokes equations allowed the detection of the boundary layer separation in all turbine components as well as the loss analysis both at design and off-design operating conditions. By 2000, the solution of the steady Reynolds averaged Navier–Stokes (RANS) equations, based on the finite volume modelling

methods, was demonstrated to be the only tool for realistically analysing the onset of pump-turbine instabilities as well as of viscosity-based secondary flows and hence became the state-of-art in the major refurbishment projects [78].

4.1. Interface model between rotating and stationary components

The comparison between numerical and experimental results are strongly influenced by boundary conditions, which are not at all easy to set when different components, rotating and stationary, are fluid-dynamically coupled to each other.

Test data of a Francis turbine [79] have demonstrated that the pronounced low pressure peak at runner inlet cannot be revealed by CFD analyses when, as in the case of boundary conditions at the runner inlet, the experimental inlet velocity profiles (circumferentially averaged) are adopted. Instead, a good adherence between numerical and experimental tests may be observed when a stacking technique between stationary upstream guide vanes and the rotor is considered (Fig. 10) and nowadays this technique represents a well-consolidated approach for numerical studies on cavitating flows in Francis turbines [80].

During the mid-80s the development of interface models between rotating and stationary domains made it possible to appraise the interaction between adjacent turbomachinery components, opening the era of CFD simulations of entire turbines. This interaction was modelled by more or less sophisticated mathematical algorithms, whose common peculiarity was to reduce the time-dependent interaction between rotating and stationary components to a steady-state problem. These algorithms modelled in a different way the transportation of the stator/rotor blade wakes across the interface, resulting in an interface represented by a circumferential mixing plane or by a locally non-uniform flow field, depending on the algorithm. However, unlike the transient interface approach, blade wakes driven by the flow through a stator-rotor interface could not be detected adequately when a steady frozen-rotor interface algorithm was adopted, owing to the possible occurrence of over-estimations of the wake disturbance effects [81].

The ability and capability of modelling the flow through the entire machine in a single CFD simulation further boosted the use of the CFD analysis, favouring its evolution from a design tool into a high-level analysis tool, as it is today, to be used in all stages of the refurbishment, from the feasibility study to the design and optimization phase.

In spite of these significant advances, the need of investigating the unstable behaviour of turbine and pump-turbine to enlarge their operating range will require further improvements in CFD in order to model turbulent flow and performance at a wider range of discharge rates more accurately and faster.

4.2. Pelton CFD

In recent years, significant developments in CFD testified by the accurate results of the numerical analysis on Francis and Kaplan turbines, and paved the way for the exploitation of CFD even to the more complex Pelton turbines.

Unlike the Francis and Kaplan turbines, whose design procedures are well-consolidated also thanks to CFD, Pelton turbines are still characterized by semi-empirical design criteria because of the difficulty in investigating (both experimentally and numerically) the complex fluid-dynamical interaction between the water jet and the rotating buckets, which greatly affects turbine performance.

With the last improvements in computational accuracy and efficiency, the experimental investigations were successfully combined with numerical analyses to gain new insights in such complex phenomena.

Following some attempts at studying a moving Pelton turbine bucket, it was only in 2006 that Perrig et al. [82] succeeded in performing a numerical analysis of the cutting process of axial-symmetric jets on the bucket cut-out, whereas Santolin et al. [83] analysed the effects of a real jet on the cutting process of a complete single-injector and rotating Pelton turbine, including both the penstock and casing. Fig. 11 [83] shows details of the computational grid of the numerically analysed single-jet Pelton turbine and of the secondary flows developing in the real jet outside the gate, generated by the forces induced by the penstock and the gate itself. The consequent deformed jet shape was shown to modify the jet–bucket interaction in comparison with an ideal axial-symmetric jet, thus causing a low-efficient energy exchange (hydraulic efficiency reduction of about 2%).

Even though this analysis was able to simulate an entire working cycle of the bucket with a good torque prediction, the Eulerian approach, on which it was based, did not make it possible to analyse more in depth the complex evolution of the free-surface flow pattern and, therefore, appreciate the influence of the bucket geometry on the turbine performance. To overcome this shortcoming, numerical simulations based on fully Lagrangian meshless approaches were carried out and attempts to simulate the flow inside Pelton buckets were also made by adopting the Smoothed

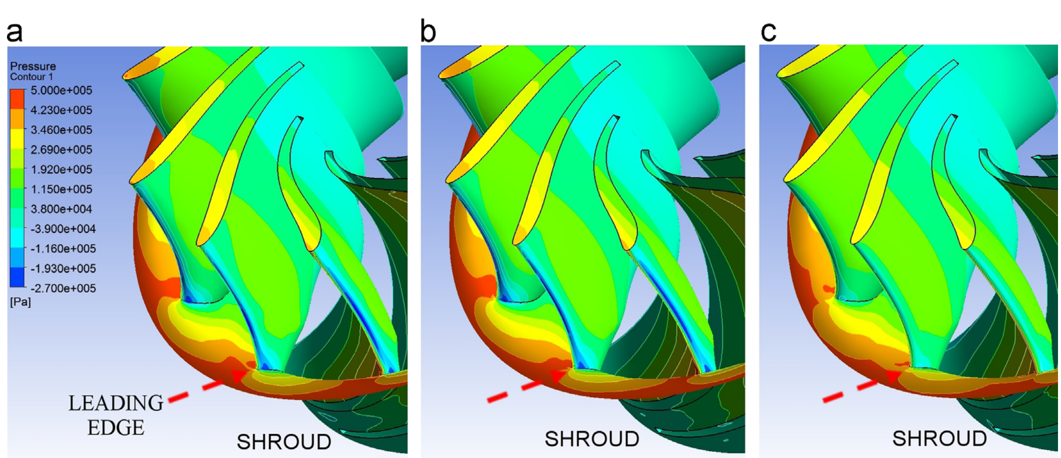

Fig. 10. Comparison between numerical results obtained adopting a frozen rotor interface model (a), a stage interface model (b) and circumferentially averaged velocity profiles (c).

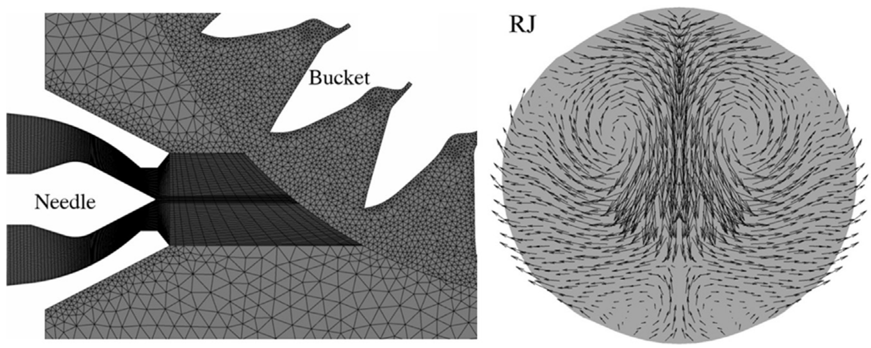

Fig. 11. CFD analysis of a single-jet Pelton turbine [83].

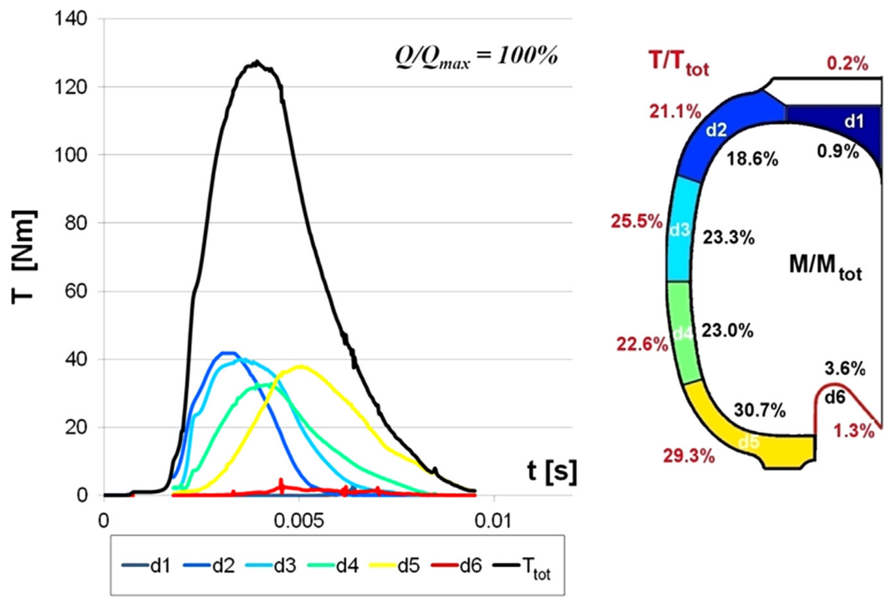

Fig. 12. Results of the hybrid Eulerian–Lagrangian approach: contributions of the different bucket discharging areas to the total bucket torque [87].

Particle Hydrodynamics (SPH) method [84,85] and the hybrid SPH–ALE method [86], based on the combination of the SPH method and an Arbitrary Lagrange Euler (ALE) one. However, even though these meshless approaches have shown their good capability for predicting complex free surface flow fields, their accuracy still remains not satisfactory and further improvements are required, as demonstrated by the lack of application examples.

An alternative and accurate method for analysing the free surface flow in a Pelton bucket on the basis of a combined Eulerian–Lagrangian approach was developed by Rossetti et al. [87]. A traditional mesh-based Eulerian approach is adopted to simulate the flow field in the runner bucket in order to exploit the acknowledged accuracy and stability of the mesh-based methods. Subsequently, to overcome the above mentioned analysis limits of this method, the numerical results were properly processed on the basis of a Lagrangian approach to determine the particle trajectories in the runner bucket as well as the variations of all the energy quantities along these trajectories. This hybrid Eulerian–Lagrangian analysis method made it possible examine the deviation capability of the different bucket areas and to determine the influence of the bucket geometry on turbine performance during the jet–bucket interaction (Fig. 12) and thereby suggest possible solutions for optimizing bucket design.

The significant advances of the recent years in the analysis of the complex free surface flow of Pelton turbines have favored the development of innovative but undeveloped design procedure [71,87]. However, to define standardized and consolidated design criteria, as those developed for other hydraulic turbines, more accurate and faster analyses of the complex free surface flow of Pelton turbines are needed and a further development of the SPH method certainly represents one of the most interesting challenge.

4.3. CFD-based runner design approaches for the rehabilitation of old small hydro power plants

In the past, the design of new turbines was usually based on previous well proven, tried and tested designs and/or proper model tests in order to guarantee high efficiency power conversion. In the last years, the restrictive environmental requirements have significantly limited the development of new plants, with a consequent huge demand for the rehabilitation and repowering of old small and micro-hydro plants to satisfy the corresponding increase in the demand of renewable electricity production. However, in the rehabilitation and upgrading of existent old plants, a new challenge had to be faced as the design of new runners had to match the already existing stationary parts. Because of the numerous constrains imposed by the existing components and the uncertainties connected to the attainment of the demand in power increase, the consolidated, at the time, experience-based design methods were abandoned and new CFD-based design approaches started to develop. These approaches swiftly demonstrated their ability in analysing different and also complex design configurations, making way for significant improvements in turbine design. However, in spite of the

increased understanding of turbine inner fluid-dynamics, the lack of information on how to modify the runner blade for improving turbine performance forced the designers towards time-consuming trial and error approaches, whose operating field was limited within the bounds of the previous successful design solutions.

A significant improvement in the runner design was achieved by the development of the 3D inverse design methods, whose main peculiarity is to use hydrodynamic parameters, such as the blade loading [88], to determine the blade shape.

Briefly, the blade loading, selected as the main design parameter, is fixed by imposing the distribution of the derivative $\partial(rV_u)/\partial m$ along the mean meridional blade section, that could be associated to the pressure difference across the blade by the following expression:

$$p^+ - p^- = \rho \frac{2\pi}{z} V_m \frac{\partial(rV_u)}{\partial m} \tag{10}$$

where p^+ and p^- represent the static pressure on the blade pressure and suction side respectively, z is the number of blades, ρ is the density, V_m and V_u the pitch-wise averaged meridional and tangential velocity respectively.

Once V_u has been evaluated by the following relation:

$$V_u = \frac{1}{r} \int \frac{\partial(rV_u)}{\partial m} dm \tag{11}$$

the average relative flow angle

$$\beta = \tan^{-1} \frac{V_m}{U - V_u} \tag{12}$$

and the mean-line blade angle

$$\beta_b = \tan^{-1} \frac{V_m}{U - V_u - (U_s/U)U} \tag{13}$$

can be determined along the considered blade section, where U_s/U is the dimensionless slip velocity factor.

Finally, for a given radial distance from the runner/rotor axis, the angular coordinate ϑ of the blade is obtained by

$$\theta = \int_{r_1}^{r} \frac{dm}{r \tan \beta} \tag{14}$$

where r_1 is the radial distance of the leading edge.

Besides the blade loading distribution at two or more spanwise sections, this method requires input design parameters: meridional channel shape, number of blades, inlet flow conditions in terms of total pressure and velocity components, inlet and exit rV_u distribution, stacking condition (the blade leading edge is not aligned along the axial direction at the rotor inlet). These input parameters perfectly comply with the design constraints imposed by the existing stationary parts in the rehabilitation and upgrading of old plants. This peculiarity, shared by all 3D inverse design methods, has significantly improved the effectiveness of CFD-based design methods, thereby reducing the empirical aspects of the former trial and error methods and increasing the runner design space.

The application of these methods in the runner design has already determined important design breakthroughs such as the improvements of cavitation performance and hydraulic efficiency [88–90] of pump-turbine and Francis turbines, swiftly demonstrating to be a proper and revolutionary design strategy in the rehabilitation of small hydroelectric plants. However, further improvements in runner design criteria are still required in order to reach high efficiency values and to match innovative design solutions, such as variable-speed runners, with the existing stationary parts of the plant.

5. Conclusions

One of the main goal of the Climate and Energy Policy of the European Union is to achieve a 20% share of renewable energies in the overall EU energy consumption by 2020, and the possibility of increasing this share up to 100% by 2050 is under consideration of the European Renewable Energy Council (EREC).

In such a context, hydropower plays a key role not only as a renewable and sustainable energy source, whose potential is estimated to be still very large, but also as a large-scale energy storage technology, commonly recognized as being one of most cost-efficient among those technologies currently available. As a result, a renewed interest in pumped hydro energy storage plants and a huge demand for the rehabilitation and repowering of old mini and micro-hydro plants are emerging globally.

As regards pumped hydro energy storage plants, the need for integrating a significant share of intermittent renewable energy sources in the grid has turned the attention of research towards the development of PHES plants which are as flexible as possible in order to provide frequency regulation. To tackle this challenge, several studies have been carried out on innovative design solutions and advances in technology have been obtained with the development and application of variable-speed pump-turbine units, whose unstable behaviours in both the operating modes are still under study. Moreover, as a consequence of the new role of PHES in the grid, optimal operating strategies, based on both simple algorithms and more complex optimization theories, have been developed to maximize the plant profitability in the deregulated energy market.

The increasing need for a better and wider exploitation of the hydropower source has also turned the attention of the research community towards the development of more or less complex algorithms for an optimal preliminary sizing of the plant capacity, on the basis of economic, technical or techno-economic parameters. Moreover, to increase the economic appeal of small-hydro power plants, and hence to favour their further deployment, innovative management strategies have been proposed to increase plant life time and operating range, and for maximizing the profitability when significant inflow and market fluctuations occur. A significant reduction in investment costs also resulted from the rehabilitation and upgrading of existent old plants. To face the numerous constrains imposed by existing plants, innovative design approaches, based on computational fluid dynamics, were proposed over the last few decades, and highly advanced design solutions were obtained in terms of operating range extension and hydraulic efficiency.

Hydropower has all the features needed for being a sustainable, secure and competitive energy and for supporting a significant penetration of other important renewable energy sources, such as wind and photovoltaic. However, even though its future not only in Europe but all around the world could be bright, there is a lot to do to make the technology more efficient, reduce its environmental impact, modernize old plants, integrate smaller plants into the grid and optimize sizing and management. This paper gives a picture of the issues and challenges facing the hydro technology sector and assesses the priorities for future research and development with a particular focus on pumped-hydro energy storage plants and small hydro power plants.

References

[1] I.E.A. Key World Energy Statistics © OECD/IEA; 2012.
[2] I.E.A. Technology Roadmap: Hydropower © OECD/IEA; 2012.
[3] European Commission. Technology map of the European strategic energy technology plan (SET-Plan) – Part I: Technology descriptions, JRC-SETIS work group, EUR 24979EN; 2011.

[4] Nazari ME, Ardehali NM, Jafari S. Pumped-storage unit commitment with considerations for energy demand, economics, and environmental constraints. Energy 2010;35:4092–101.
[5] Franco A, Salza P. Perspectives for the long-term penetration of new renewables in complex energy systems: the Italian scenario. Environ, Dev Sustainab 2011;13:309–30.
[6] Purvins A, Papaioannou IT, Oleinikova I, Tzimas E. Effects of variable renewable power on a country-scale electricity system: High penetration of hydro power plants and wind farms in electricity generation. Energy 2012;43 (1):225–36.
[7] European Transmission System Operators. European Wind Integration Study (EWIS) Towards a Successful Integration of Large Scale Wind Power into European Electricity Grids. Final Report, © ENTSO-E; 2010.
[8] Söder L, Abildgaard H, Estanquiero A, Hamon C, Holttinen H, Lannoye E, et al. Experience and challenges with short-term balancing in European systems with large share of wind power. IEEE Trans Sustainable Energy 2012;3: 853–61.
[9] Electric Power Research Institute (EPRI-DOE). Electric energy storage technology options: a white paper primer on applications, costs and benefits, Palo Alto, CA, 1020676; 2010.
[10] Weisser D, Garcia RS. Instantaneous wind energy penetration in isolated electricity grids: concepts and review. Renew Energy 2005;30(8):1299–308.
[11] Padron S, Medina JF, Rodriguez A. Analysis of a pumped storage system to increase the penetration level of renewable energy in isolated power systems. Gran Canaria: a case study. Energy 2011;36:6753–62.
[12] Anagnostopoulos JS, Papantonis DE. Study of pumped storage schemes to support high RES penetration in the electric power system in Greece. Energy 2012;45:416–23.
[13] Tuohy A, O′Malley M. Pumped storage in systems with very high wind penetration. Energy Policy 2011;39:1965–74.
[14] Dursun B, Alboyaci B. The contribution of wind-hydro pumped storage systems in meeting Turkey′s electric energy demand. Renew Sustainan Energy Rev 2010;14:1979–88.
[15] Benitez LE, Benitez PC, Cornelis van Kooten G. The economics of wind power with energy storage. Energy Econ 2008;30:1973–89.
[16] Steffen B. Prospects for pumped-hydro storage in Germany. Energy Policy 2012;45:420–9.
[17] Yang C-J, Jackson RB. Opportunities and barriers to pumped-hydro energy storage in the United States. Renew Sustainable Energy Rev 2011;15:839–44.
[18] Kapsali M, Kaldellis JK. Combining hydro and variable wind power generation by means of pumped-storage under economically viable terms. Appl Energy 2010;87:3475–85.
[19] Ibrahim H, Ilinca A, Perron J. Energy storage systems – characteristics and comparisons. Renew Sustainable Energy Rev 2008;12:1221–50.
[20] Kazempour SJ, Moghaddam MP, Haghifam MR, Yousefi GR. Electric energy storage systems in a market-based economy: comparison of emerging and traditional technologies. Renew Energy 2009;34(12):2630–9.
[21] Lopes Ferreira H, Garde R, Fulli G, Kling W, Pecas Lopes J. Characterisation of electrical energy storage technologies. Energy 2013;53(1):288–98.
[22] Loisel R. Power system flexibility with electricity storage technologies: a technical-economic assessment of a large-scale storage facility. Int J Electr Power 2012;42(1):542–52.
[23] Rangoni B. A contribution on electricity storage: the case of hydro-pumped storage appraisal and commissioning in Italy and Spain. Util. Policy 2012;23:31–9.
[24] Deane JP, O. Gallachoir BP, McKeogh EJ. Techno-economic review of existing and new pumped hydro energy storage plant. Renew Sustainable Energy Rev 2010;14:1293–302.
[25] Ekman CK, Jensen SH. Prospects for large scale electricity storage in Denmark. Energy Convers Manag 2010;51:1140–7.
[26] Kaldellis JK, Zafirakis D, Kavadias K. Techno-economic comparison of energy storage systems for island autonomous electrical networks. Renew Sustainable Energy Rev 2009;13:378–92.
[27] Daim TU, Li X, Kim J, Simms S. Evaluation of energy storage technologies for integration with renewable electricity: Quantifying expert opinions. Environ Innov Soc Transit 2012;3:29–49.
[28] Connolly D, MacLaughlin S, Leahy M. Development of a computer program to locate potential sites for pumped hydroelectric energy storage. Energy 2010;35:375–81.
[29] Pickard WF. The history, present state, and future prospects of underground pumped hydro for massive energy storage. Proc IEEE 2011;100 (2):473–83.
[30] Uddin N. Geotechnical issues in the creation of underground reservoirs for massive energy storage. Proc IEEE 2012;100(2):484–92.
[31] European Commission. European energy pocket book; 2009. Available from: 〈http://ec.europa.eu/energy/publications/statistics/statistics_en.htm〉.
[32] Ciocan GD, Teller O, Czerwinski F. Variable Speed Pump-Turbines Technology. UPB Scient Bull, Ser D: Mech Eng 2012;74(1):33–42.
[33] Suul, JA, Uhlen, K, Undeland, T. Wind Power Integration in Isolated Grids enabled by Variable Speed Pumped Storage Hydropower Plant. 2008 IEEE Int Conf Sust Energ Technologies, ICSET, 2008; pp. 399–404.
[34] Schoenung, SM, Hassenzahl, WV. Long - vs. Short-Term Energy Storage Technologies, Analysis. Sandia Report, SAND2003-2783 ; 2003.
[35] Genter, Ch, Sallaberger, M, Widmer, Ch, Braun, O, Staubli, T. Analysis of unstable operation of pump turbines and how to avoid it. Hydro, 29–31 October, Bilbao, Spain; 2012.
[36] Pavesi G, Cavazzini G, Ardizzon G. Time-frequency characterization of the unsteady phenomena in a centrifugal pump. Int J Heat Fluid Flow 2008;29:1527–40.
[37] Cavazzini G, Pavesi G, Ardizzon G. Pressure instabilities in a vaned centrifugal pump. Proc Inst Mech Eng A J Power 2011;225:930–9.
[38] Lu N, Chow JH, Desrochers AA. Pumped-storage hydro-turbine bidding strategies in a competitive electricity market. IEEE Trans Power Syst 2004;19(2):834–41.
[39] Castronuovo ED, Peças Lopes JA. Optimal operation and hydro storage sizing of a wind–hydro power plant. Int J Elec Power 2004;26:771–8.
[40] Connolly D, Lund H, Finn P, Mathiesen BV, Leahy M. Practical operation strategies for pumped hydroelectric energy storage (PHES) utilising electricity price arbitrage. Energy Policy 2011;39:4189–96.
[41] Khatibi M, Jazaeri M. An analysis for increasing the penetration of renewable energies by optimal sizing of pumped-storage power plants. IEEE Electr Power Energy Conf – Energy Innov 2008; October:1–5. (Article No. 4763324).
[42] Dursun B, Alboyaci B, Gokcol C. Optimal wind-hydro solution for the Marmara region of Turkey to meet electricity demand. Energy 2011;36:864–72.
[43] Bueno C, Carta JA. Wind powered pumped hydro storage systems, a means of increasing the penetration of renewable energy in the Canary Islands. Renew Sustainable Energ Rev 2006;10:312–40.
[44] Ding H, Hu Z, Song Y. Stochastic optimization of the daily operation of wind farm and pumped-hydro-storage plant. Renew Energy 2012;48:571–8.
[45] Cheng C-t, Liao S-l, Tang Z-T, Zhao M-y. Comparison of particle swarm optimization and dynamic programming for large scale hydro unit load dispatch. Energy Convers Manag 2009;50:3007–14.
[46] Catalao JPS, Pousinho HMI, Mendes VMF. Hydro energy systems management in Portugal: profit-based evaluation of a mixed-integer nonlinear approach. Energy 2011;36:500–7.
[47] Yin X-L, Yang Y. Solving economical operation problem of basin cascade plants based on bi-level coupling genetic algorithm. Appl Mech Mater 2013;357–360:2921–4.
[48] Rajan A. Hydro-thermal unit commitment problem using simulated annealing embedded evolutionary programming approach. Int J Elec Power 2011;33: 939–46.
[49] Afshar MH, Moeini R. Partially and fully constrained ant algorithms for the optimal solution of large scale reservoir operation problems. Water Resour Manag 2008;22(12):1835–57.
[50] Wang J, Liu S. Quarter-hourly operation of hydropower reservoirs with pumped storage plants. J Water Resour Plan Manag – ASCE 2011;138(1):13–23.
[51] Cheng C, Liao S, Tang Z, Zhao M. Comparison of particle swarm optimization and dynamic programming for large scale hydro unit load dispatch. Energy Convers Manag 2009;50:3007–14.
[52] Kang, Q, Wang, JA, Wu, Q. A Heuristic Stochastic Dynamic Programming Method for Discrete Particle Swarm Optimizer System. IEEE Int C Netw Sens, Okayama, Japon, March, 26–29; 2009.
[53] Afshar MH. Large scale reservoir operation by constrained particle swarm optimization algorithms. J Hydro-environ Res 2012;6:75–87.
[54] Mahor A, Rangnekar S. Short term generation scheduling of cascaded hydro electric system using novel self adaptive inertia weight PSO. Int J Elec Power 2012;34:1–9.
[55] Zhang R, Zhou J, Ouyang S, Wang X, Zhang H. Optimal operation of multi-reservoir system by multi-elite guide particle swarm optimization. Int J Elec Power 2013;48:58–68.
[56] Okot DK. Review of small hydropower technology. Renew Sustainable Energy Rev 2013;26:515–20.
[57] Mishra S, Singal SK, Khatod DK. A review on electromechanical equipment applicable to small hydropower plants. Int J Energy Res 2012;36(5):553–71.
[58] Yi C-S, Lee J-H, Shim M-P. Site location analysis for small hydropower using geo-spatial information system. Renew Energy 2010;35(4):852–61.
[59] Hosseini S, Forouzbakhsh F, Rahimpoor M. Determination of the optimal installation capacity of small hydro-power plants through the use of technical, economic and reliability indices. Energy Policy 2005;33:1948–56.
[60] de Almeida Lopes JPPG, LejeuneHenri AG, Sa Marques JAA, Cunha MC. OPAH a model for optimal design of multipurpose small hydropower plants. Adv Eng Softw 2006;37(4):236–47.
[61] Anagnostopoulos JS, Papantonis DE. Optimal sizing of a run-of river small hydropower plant. Energy Convers Manag 2007;48(10):2663–70.
[62] Niadas IA, Mentzelopoulos P. Probabilistic flow duration curves for small hydro plant design and performance evaluation. Water Resour Manag 2008;22:509–23.
[63] Peňa R, Medina A, Anaya-Lara O, McDonald J. Capacity estimation of a minihydro plant based on time series forecasting. Renew Energy 2009;34: 1204–9.
[64] Borges CLT, Pinto RJ. Small hydro power plants energy availability modeling for generation reliability evaluation. IEEE Trans Power Syst 2008;23 (3):1125–35.
[65] Bockman T, Fleten S-E, Juliussen E, Langhammer HJ, Revdal I. Investment timing and optimal capacity choice for small hydropower projects. Eur J Oper Res 2008;190:255–67.
[66] Santolin A, Cavazzini G, Pavesi G, Ardizzon G, Rossetti A. Techno-economical method for the capacity sizing of a small hydropower plant. Energy Convers Manag 2011;52:2533–41.
[67] Liu Y, Ye L, Benoit I, Liu X, Cheng Y, Morel G, et al. Economic performance evaluation method for hydroelectric generating units. Energy Convers Manag 2003;44(6):797–808.

[68] Garrido J, Zafra Á, Vázquez F. Object oriented modelling and simulation of hydropower plants with run-of-river scheme: a new simulation tool. Simul Model Pract Theor 2009;17(10):1748–67.
[69] Fleten SE, Kristoffersen TK. Short-term hydropower production planning by stochastic programming. Comput Oper Res 2008;35(8):2656–71.
[70] Catalao JPS, Pousinho HMI, Mendes VMF. Optimal hydro scheduling and offering strategies considering price uncertainty and risk management. Energy 2012;37:237–44.
[71] Santolin, A, Pavesi, G, Cavazzini, G, Ardizzon, G. Variable-speed Pelton turbine for an efficient exploitation of the reserved flow: an Italian case study. Int J Hydropower Dams. Promoting the Versatile Role of Hydro, Innsbruck, Austria; 7–9 October 2013: pp. 1–13.
[72] Wislicenus GF. Fluid mechanics of turbomachinery. Book Company Limited. London, UK: McGraw-Hill; 1947.
[73] Horlock JH. Axial flow compressors: fluid mechanics and thermodynamics. London, UK: Butterworths Scientific Publications; 1958.
[74] Hoffmann, KA, Chiang, ST. Computational fluid dynamics for engineers. Engineering Education System, Wichita, Kansas, 67298-1078, USA; 1993.
[75] Zienkiewicz OC. The finite element method. 3rd ed. London, UK: McGraw-Hill Book Company Limited; 1977; 1977.
[76] Wu, CH. A General Theory of Three-dimensional Flow in Subsonic Turbomachines of Radial-Axial- and Mixed Flow Types. NACA TN-D 2604; 1952.
[77] Ardizzon G, Pavesi G. Influence of the blade stacking on the flow through an axial flow runner and predictions of three-dimensional and quasi three-dimensional numerical codes. Proc Inst Mech Eng 1990;204:389–97.
[78] Ansys CFX, Release 14.0, Ansys, Inc., Canonsbury, PA.
[79] Göde, E. (1989) A Stacking technique for multistage 3D flow computation in hydraulic turbomachinery. GAMM Workshop, Lausanne; 1989.
[80] Zhang H, Zhang L. Numerical simulation of cavitating turbulent flow in a high head Francis turbine at part load operation with OpenFOAM. Procedia Eng 2012;31:156–65.
[81] Keck H, Sick M. Thirty years of numerical flow simulation in hydraulic turbomachines. Acta Mech 2008;201:211–29.
[82] Perrig A, Avellan F, Kueny JL, Farhat M, Parkinson E. Flow in a Pelton turbine bucket: numerical and experimental investigations. J Fluid Eng – T ASME 2006;128(4):350–8.
[83] Santolin A, Cavazzini G, Ardizzon G, Pavesi G. Numerical Investigation of the Interaction between Jet and Buckets in a Pelton Turbine. Proc Inst Mech Eng A J Power 2009;223(6):721–8.
[84] Gomez-Gesteira M, Rogers BD, Dalrymple RA, Crespo AJC. State-of-the-art of classical SPH for free-surface flows. J Hydraul Res 2010;48:6–27.
[85] Marongiu J-C, Leboeuf F, Parkinson E. Numerical simulation of the flow in a Pelton turbine using the meshless method smoothed particle hydrodynamics: a new simple solid boundary treatment. Proc Inst Mech Eng A J Power 2007;221:849–56.
[86] Marongiu J-Ch, Leboeuf F, Caro J, Parkinson E. Free surface flows simulations in Pelton turbines using an hybrid SPH–ALE method. J Hydraul Res 2010;48 (S1):40–9.
[87] Rossetti A, Pavesi G, Cavazzini G, Santolin A, Ardizzon G. Influence of the bucket geometry on the Pelton performance. Proc Inst Mech Eng A J Power http://dx.doi.org/10.1177/0957650913506589, in press.
[88] Yang W, Xiao R. Multiobjective optimization design of a pump–turbine impeller based on an inverse design using a combination optimization strategy. J Fluid Eng – T ASME 2014;136(1):1–9.
[89] Daneshkah, K, Zangeneh, M. Parametric design of a Francis turbine runner by means of a three-dimensional inverse design method. In: Proceedings of the XXV IAHR Symp on Hydraulic Mach Syst; 2010.
[90] Choi H-J, Zullah MA, Roh H-W, Ha P-S, Oh S-Y, Lee Y-H. CFD validation of performance improvement of a 500 kW Francis turbine. Renew Energy 2013;54:111–23.